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Bechtel Corp, San Francisco, Calif

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FLUE GAS DESULFURIZATION SYSTEMS: DESIGN AND OPERATING CONSIDERATIONS

Volume I. Executive Summary

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16. ABSTRACT The report describes flue gas desulfurization (FGD) systems and the design and operating parameters that are monitored to ensure proper operation. It explains how these parameters are varied to accommodate changing boiler loads and fuel characteristics, and describes the control of parameters to prevent such problems as scale buildup. It describes effects of designing and operating FGD systems for 90% or greater SO2 removal efficiencies, based on current testing program data. It describes effects of coal characteristics on FGD performance, along with operating and design techniques used to compensate for coal property variations. It describes the purpose, need, and methods for exhaust gas reheat, downstream of FGD systems. It discusses alternatives to exhaust gas reheat.

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Volume I. Executive Summary

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FOREWORD

EPA has undertaken a review of the New Source Performance Standards for SO_2 emissions from coal-fired steam generators. As part of this review, EPA is assembling information related to the SO_2 removal capability of FGD systems and technical and economic data for the design of FGD systems for higher SO_2 removal efficiencies.

In the conduct of this review the EPA has contracted for the services of a number of supporting organizations, each of which will make specific contributions to the total subject. In this respect, a substantial number of separate, but related, issues will be investigated, including such broad issues as economic, energy, social, technological, and environmental issues.

This report addresses itself to the following specific tasks:

(1) Describe FGD system parameters which are commonly monitored to ensure proper operation and explain how those parameters are varied to accommodate combustion system variations such as changing boiler loads, changes in SO_2 inlet concentrations, and changes in other fuel characteristics. Describe the parameters which are controlled to limit scale build-up in the scrubber system and mist eliminator and the ranges within which they must be controlled and parameters which are controlled to limit other problems.

(2) Where an installed full-scale FGD system has demonstrated good operation, but at lower SO_2 removal efficiencies (such as 60 to 85 percent), define the changes that would be applied to a new facility to obtain 90 percent or greater SO_2 removal and present data showing the effects of these changes. For example,

SO_2 removal efficiency may be increased by increasing the liquid-to-gas ratio, changing pH, addition of MgO to lime/limestone scrubbers, changes in scrubber gas velocity, increasing bed heights in absorption towers, and others. Any rationale, engineering calculations, etc., necessary to extrapolate from an existing FGD system operating well at lower percent SO_2 removal to a 90 percent or greater SO_2 removal should be presented.

(3) Define the effects of changes in coal characteristics on FGD systems and describe operating parameters or design techniques which can be used to compensate for local and nationwide variations in coals. For example, coals with high chloride contents affect SO_2 removal efficiency, may corrode FGD constituents, and may require the purge of additional waste streams. As another example, describe the effects of different coals on the resultant mixture of combustion gases (e.g., percent oxygen in exhaust) and the resulting effects on the chemical reactions and efficiency of the scrubber. Define the scrubber system parameters which are controlled to compensate for these variations.

(4) Describe the purpose, need, and methods for reheat of exhaust gases downstream of FGD systems. Define energy consumption for reheat of these gases for typical plants ranging in size from 25 to 1000 megawatts for the different FGD systems. Describe problems experienced with reheaters and design and operating or maintenance factors used to satisfactorily overcome these problems. Assess approaches which have been or could be used to eliminate reheat of these gases.

As used herein, the term "SO_2 removal efficiency" is limited to performance obtained from a single module of removal equipment over a short time, and tested over a period of several weeks to show that scale accumulation is not likely. The term does not reflect the longer periods of time necessary for commercial operations, nor any implication concerning the equipment reliability or availability. Inasmuch as increasing the percent SO_2 removal above currently demonstrated levels will require greater chemical work, it will inherently cause some reduction in the equipment reliability and availability unless suitable counteracting steps (such as the use of more modules)

are taken. It will also somewhat increase the energy consumption requirements, the chemical feed requirements, and the waste disposal requirements over those currently being used. It is understood that these specific subjects, their quantification, and potential solutions are being addressed by others and that their results will be integrated with the results reported herein. Thus, the results contained in this report should not be construed as a complete assessment of all factors related to the judgment as to the establishment of SO_2 removal New Source Performance Standards.

This volume is an executive summary of the above report.

ABSTRACT

A brief introduction is given to flue gas desulfurization technology. The SO_2 removal mechanisms for wet scrubbing and dry processes are described, along with the typical gas contacting equipment used. Processes and their critical operating parameters are described for:

- Lime and limestone scrubbing
- Sodium carbonate scrubbing
- Double alkali (soda lime) scrubbing
- Magnesium oxide scrubbing
- Sodium sulfite (Wellman Lord) scrubbing

The report describes the implications of requiring 90 percent or greater SO_2 removal for new FGD installations. For lime and limestone scrubbing data are presented from the EPA Shawnee Test Facility to show the effects of process operating parameters on SO_2 removal efficiency. Mathematical correlations of the data are also presented. Additional test data is presented for sodium carbonate and double alkali scrubbing.

Coal characteristics and their effects on FGD system design and operation are summarized. A qualitative description is given for the effects of coal heating value and sulfur, ash, moisture, and chlorine content.

The reasons and methods for reheating scrubbed flue gases are described. Energy consumption of the various methods is defined, and problems experienced with reheater design, operation, and maintenance are presented. Alternative approaches to eliminating reheat are discussed.

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SUMMARY

FGD PROCESSES

All commercial flue gas desulfurization (FGD) installations operating on U.S. coal-fired utility boilers are wet scrubbing processes that contact the flue gas with a water solution of soluble (or sparingly soluble) alkali to absorb the SO_2. The SO_2 removal is carried out in devices (scrubbers) designed to provide intimate contact between gas and liquid over a large gas-liquid interface area. The SO_2 removal efficiency of an FGD system is a function of the type of scrubber selected, the absorbent composition and circulation rate to the scrubber, and additional operating parameters.

Table 1 summarizes by process the number and capacity of full scale operational FGD systems and systems under construction on utility boilers in the U.S.

A major distinction is generally made between recovery processes, which recover SO_2 in useful forms such as sulfuric acid or elemental sulfur, and throwaway processes, which produce a solid or liquid waste. In the throwaway case, the waste product must be stored in a pond or treated and used for landfill.

Wet FGD processes fall into two classifications — slurry scrubbing and clear liquor. In slurry scrubbing the absorbent and reaction products are present as suspended solid particles in water. During the absorption phase of slurry scrubbing, the suspended alkali dissolves to react with the absorbed SO_2 and to precipitate waste solids which are disposed of in throwaway processes or treated to regenerate active

Table 1

SUMMARY OF FGD PROCESSES ON U.S. COAL-FIRED UTILITY BOILERS

Process	Operational		Construction		Contract Awarded	
	No.	MW	No.	MW	No.	MW
Limestone	9	3,767	16	6,750	10	4,91[illegible]
Lime	9	2,702	9	4,158	4	2,350
Alkaline fly ash with lime or limestone	2	720	1	450	2	1,400
Sodium carbonate	3	375	–	–	1	509
Magnesium oxide	1	120	–	–	–	–
Double alkali	–	–	1	575	2	527
Wellman Lord	1	115	2	715	–	–
Aqueous carbonate	–	–	–	–	1	100

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alkali in recovery processes. The circulation of saturated solutions and crystallization of reaction products makes the control of process chemistry very important to prevent scaling in the scrubber. Slurry system components are also vulnerable to plugging and erosion. Clear liquor scrubbing processes minimize the problems of the slurry systems by keeping the absorbent and reaction products dissolved in water.

Some wet scrubbers are suitable for the removal of both fly ash and SO_2 so that, for a new power plant, one of the options for the control of these pollutants may be to let the FGD system remove both. In practice, however, there are some valid reasons for collecting fly ash separately with an electrostatic precipitator. For example, possible interference with process chemistry is prevented, erosion of process equipment by fly ash slurry is minimized, contribution to additional throwaway sludge volume is avoided (although the fly ash must still be disposed of), and, in the case of recovery processes, contamination of by-products is prevented. Another consideration is that if the power plant has an FGD system bypass and separate dust removal equipment, particulate removal operation can be continued during periods of FGD system maintenance (if such operation is allowed).

In a wet scrubber the flue gas is cooled by evaporation of water. It may then be desirable to reheat the gas to minimize condensation, fouling, and corrosion in ducts, fans, and stacks; to avoid a visible plume; and to improve plume rise and dispersion.

Lime and Limestone Scrubbing

Of the potentially available processes, lime and limestone slurry scrubbing have received the most attention and are presently operating on a number of coal-fired boilers. Additional new units are under construction. These processes achieve high SO_2 absorption efficiencies, use naturally occurring raw materials, produce relatively insoluble

wastes, and have lower capital and operating costs than many other processes. Significant improvements have been made over the past several years in the areas of improved reliability, variable load operation, system control, and sludge disposal techniques.

Sodium Carbonate Scrubbing

Sodium carbonate scrubbing is a clear liquor absorbent process that is less susceptible to scaling than calcium-based systems. This process has had limited application because it consumes an expensive alkali and produces a soluble sodium waste product that must either be regenerated at a substantial cost or impounded in suitably lined retention ponds. To date, application has been limited to geographical areas having a cheap source of low-grade carbonate; these include three units operating at a power station in Nevada and one under construction in Wyoming.

Double Alkali Scrubbing

The double alkali process retains the desirable characteristics of the clear liquor sodium carbonate system. It minimizes the soluble waste problem by reacting the scrubber effluent with lime or limestone to precipitate an insoluble waste product and regenerate the costly sodium absorbent. However, the process operation is somewhat more complex and requires additional equipment.

Approximately 12 installations totaling 700 MW equivalent have been operated on oil-fired and coal-fired industrial boilers in the U.S. and Japan. Also, three installations totaling 1,050 MW on oil-fired utility boilers have operated in Japan, and 20 MW prototype testing has been carried out on a Gulf Power Company coal-fired utility boiler in Florida. Three full-scale units totaling 1,100 MW are scheduled for operation in the U.S. on coal-fired utility boilers.

Magnesium Oxide Scrubbing

The magnesium oxide recovery process features recovery of sulfuric acid or sulfur. It has been demonstrated to be feasible on full-scale coal-fired boilers and is capable of high SO_2 removal efficiency, although the reliability of these installations must be improved. Two full-scale installations have been operated in the U.S., one on an oil-fired boiler and the other on coal. A third unit of 120 MW is currently undergoing testing on a coal-fired boiler.

Sodium Sulfite (Wellman Lord) Scrubbing

The Wellman Lord system is a clear liquor sodium alkali scrubbing process with thermal regeneration and sulfuric acid or elemental sulfur recovery. About 17 installations are in operation in the U.S. and Japan on industrial plants and oil-fired boilers. A 115 MW installation on the coal-fired D. H. Mitchell Station of Northern Indiana Public Service has been completed and is currently undergoing a comprehensive one-year demonstration program. This is the first application of the process on a coal-fired boiler. Two additional units are under construction. This process is more complex and costly than lime and limestone scrubbing processes.

FGD System Process Control Parameters

A number of FGD system parameters must be monitored and controlled to ensure proper operation, to accommodate variations such as changing boiler load and inlet SO_2 conditions, to ensure proper mist eliminator operation, and to prevent scaling in scrubbers. These parameters include a varying alkali feed rate to match inlet SO_2 and boiler load changes, and a number of mist eliminator washing schemes and design configurations to maintain trouble-free operation. Techniques employed to prevent scaling typically include control of scrubber pH, adequate hold tank residence time, control of suspended solids concentration in slurry systems, and high liquid-to-gas ratios. Clear liquor scrubbing

processes such as the sodium carbonate, double alkali and Wellman Lord are not susceptible to scaling problems to the extent that the lime and limestone processes are.

IMPLICATIONS OF REQUIRING 90 PERCENT OR GREATER SO_2 REMOVAL FOR NEW FGD SYSTEMS

For the FGD processes described in this report, SO_2 removal efficiencies of 90 percent or greater — as defined in the foreword to this report — are obtainable by suitably changing a number of the operating conditions. This section discusses the changes in a demonstrated FGD system design of, for example, 80 percent SO_2 removal efficiency to obtain a capability of 90 percent or more. In summary, these design changes could involve:

- Increase in absorbent circulation rates
- Increase in scrubbing (contacting) stages or in contacting intensity (scrubber-type)
- More stringent requirements for uniform flow distribution
- Elimination of gas by-pass if used for reheat
- Increases in absorbent concentrations which may in turn require residence time or other changes to control enhanced scaling tendencies

If the increased SO_2 removal requirement is also accompanied by an increase in coal sulfur content, this change will intensify all of the above requirements. Other fuel related factors such as coal heating value, ash content and composition must also be accommodated and with increasing difficulty as removal requirement rises.

Lime and Limestone Scrubbing

For a given inlet SO_2 concentration, or coal sulfur content, the removal efficiency of a lime or limestone FGD system can be substantially varied by changing a number of operating conditions, including

scrubber type, liquid-to-gas ratio, gas velocity (for some scrubbers), scrubber inlet pH, magnesium addition, and the number of scrubbing stages. Raising the design efficiency of such systems to 90 percent or greater affects a number of process design parameters. Among possible required changes:

- Scrubbers. More elaborate and equally reliable scrubber modules must be engineered to provide greater slurry holdup and gas-liquid interfacial area, or existing design must be upgraded to include additional internal devices. The number of vessels could be doubled to provide operation with two scrubbers in series.

- Recycle Pumps and Piping. If L/G is increased to improve absorption efficiency, pump size is increased. Recycle slurry pipe diameters must be increased to maintain design flow velocities

- Limestone Preparation Equipment. To accommodate greater feed rates in a limestone system, larger grinding equipment, storage silos, transfer equipment, slurry makeup tanks and feed pumps, and other related equipment will be needed

- Lime Preparation Equipment. To accommodate greater feed rates in a lime system, the slaking equipment, storage silos, transfer equipment, slurry tanks and feed pumps, and other related equipment must be larger

- Magnesium Addition Equipment. If magnesium is added to improve efficiency, the magnesium handling equipment must be added to the process design, or dolomitic lime used. The waste sludge must be treated or contained to prevent groundwater contamination by the dissolved compounds

- Scrubber Recirculation Tanks. Tanks must be larger to maintain design residence time for increased L/G and to provide residence time for increased SO_2 absorption. These tanks may be directly under the scrubber, integrated into the scrubber vessel design, or offset. Slurry agitators will require redesign

- Slurry Solids Separation Equipment. This equipment must be larger to accommodate greater solids discharge. This applies to clarifiers, filters, centrifuges, and all related slurry pumps and piping

- Fans. If greater gas pressure drop is incurred, the fans must either be larger, or there must be more of them — with corresponding increases in the complexity of the fan control system

- Reheat. Bypass reheat would be marginal or impossible because all the flue gas must be treated

- Nonair Quality Environmental Effects. As SO_2 removal is increased, provision must be made for handling the increased waste products produced. If soluble additives are used to enhance absorption efficiency, steps must be taken to prevent groundwater contamination

- Energy Requirement. Power requirements would increase with larger equipment loads

This list illustrates the complexity of considerations that must be addressed in designing lime and limestone FGD systems for 90 percent or greater SO_2 removal efficiencies. Such an effort inevitably involves higher cost and energy requirements. The energy requirement will be in the form of increased auxiliary power consumption. The cost penalties can be not only in terms of heavier equipment, but of greater operating complexity and higher maintenance as well.

Sodium Carbonate Scrubbing

The sodium carbonate process is capable of high efficiency over a wide range of inlet SO_2 concentrations. This clear liquor process is gas-phase controlled — rather than being limited by the slow dissolution of suspended solids. However, as previously indicated, the process consumes a premium chemical and produces a soluble waste salt which, to avoid water pollution, must either be stored in lined impoundments or regenerated at substantial cost.

To date application for coal-fired utility plant FGD systems has been limited to geographical areas having a cheap source of low-grade carbonate. These include three units operating at a power station in Nevada (Reid Gardner — 375 MW) and one under construction in Wyoming (Jim Bridger — 520 MW). Both stations burn low-sulfur coal and the FGD systems are designed to realize about 90 percent absorption efficiency.

Double Alkali Scrubbing

The clear-liquor sodium-based double alkali process, like the sodium carbonate process, is aimed at realizing high removal efficiencies over a wide range of inlet concentrations. The absorption is gas-phase rather than solid dissolution limited. More efficient scrubber types can be used, such as packed towers and tray towers. Venturi scrubbers provide excellent SO_2 removal, although at substantial energy penalty. The process operation is somewhat more complex than lime and limestone scrubbing processes.

Double alkali FGD systems are currently being offered and designed to achieve high removal efficiency in both industrial and utility applications. The process has achieved greater than 90 percent SO_2 removal during prototype testing on a coal-fired utility boiler. The first full-scale coal-fired utility application is scheduled to start up in 1979. The system is designed to meet performance guarantees of 95 percent SO_2 removal on 5 percent sulfur coal. Construction of two additional units is planned.

Magnesium Oxide Scrubbing

As previously indicated, the magnesium oxide slurry scrubbing process has been demonstrated to be feasible on full-scale coal-fired boilers and is capable of SO_2 removal efficiencies greater than 90 percent, although the reliability of these installations must be improved. A

120 MW unit is currently undergoing testing and has been designed to achieve 90 percent SO_2 removal from 2.5 percent sulfur coal. The magnesium oxide process operation is more complex than lime and limestone scrubbing.

Sodium Sulfite (Wellman Lord) Scrubbing

The Wellman Lord recovery process has demonstrated high SO_2 absorption efficiencies on oil-fire boilers and industrial plants. A 115 MW installation on the coal-fired Mitchell Station of Northern Indiana Public Service has been completed and is currently undergoing a comprehensive one-year demonstration program. This is the first application of the process on a coal-fired boiler. The installation was designed to meet performance guarantees of 90 percent SO_2 removal from flue gas generated by 3.5 percent sulfur coal and has demonstrated greater efficiencies. Two additional units are under construction. The process operation is more complex and costly than the lime and limestone scrubbing processes.

EFFECT OF COAL PROPERTIES ON FGD SYSTEMS

The major coal properties affecting FGD system design and operation are heating value and sulfur, ash, moisture, and chlorine content.

The effects include:

- Heating value of coal. Affects flue gas flow rate — generally higher for lower heating value coals which also contribute a greater water vapor content to the flue gas

- Moisture content. Affects the heating value and contributes directly to the moisture content and volume of the flue gas

- Sulfur content. The sulfur content together with the allowable emission standards determines the required SO_2 removal efficiency, the FGD system complexity and cost, and also affects sulfite oxidation

- Ash content. May affect FGD system chemistry and increases erosion. In some cases it may be desirable to remove fly ash upstream from the FGD system

- Chlorine content. May require high alloy metals or linings for some process equipment and could affect process chemistry or require prescrubbing

The importance of these factors is described in this section.

Coal Heating Value and Moisture Content

Because a power plant using a low heating value coal must fire at a higher burn rate to generate the same amount of power, such coals produce a larger volume of flue gas and greater SO_2 emissions per unit of generated power. The effect on the FGD system is twofold. First, the flue gas handling equipment, including the scrubbers, must be of a larger size to accommodate the greater gas volumes. Typically, power plant flue gas volumes may range from 5,000 to more than 7,000 m^3/hr/MW (about 3,000 to 4,000 acfm/MW), depending on the coal composition, boiler heat rate, gas temperature, and power plant elevation (or gas pressure). Secondly, the increased SO_2 emissions mean that on a megawatt basis the FGD system must treat proportionally larger quantities of SO_2. On a megawatt basis, therefore, the FGD system (as well as the power plant) equipment capacity is greater and capital and operating costs are higher for coal with lower heating value — for a given coal sulfur content and SO_2 removal efficiency.

A characteristic of lower heating value coals and coals of high moisture content is a flue gas with a greater proportion of water vapor. This leads to smaller amounts of water evaporation in the scrubbers, which in turn affects the temperature to which the gas is cooled. The overall effect is that SO_2 absorption takes place at slightly elevated temperatures. This could affect absorption efficiency, depending on the chemistry of the particular process.

Sulfur Content of Coal

The sulfur content of the coal together with the allowable emission standards determines the absolute removal rate of SO_2 in pounds per hour. For a given absorption efficiency the sulfur content of the coal directly affects the design of almost every piece of equipment in the FGD system.

For example, a lime or limestone system designed for high rather than low sulfur coal would have:

- Scrubbers with capacity for greater SO_2 removal
- Higher L/G's and therefore bigger pumps and piping and higher pumping energy requirements
- Bigger fans and greater energy requirements if the improved scrubber design results in higher gas pressure drop
- Larger sized alkali storage, preparation and feed equipment
- Greater lime or limestone feed rates
- Larger scrubber recirculation tanks to maintain residence time for increased L/G's and to provide additional time for increased SO_2 absorption load
- Greater capacity slurry solids separation equipment
- Provision for disposing of the larger waste volumes
- Increased power requirements for the larger equipment loads

The result is that for higher sulfur coals the lime and limestone FGD systems are more complex and have higher capital and operating costs.

Other FGD processes are similarly affected by the sulfur content of the coal. For systems using regenerable absorbents (double alkali, magnesium oxide and Wellman Lord processes), the capacity of the

regeneration section is directly proportional to the sulfur content. With high sulfur coal the overall cost of these sections (capital and operating) represents a large portion of the total cost for the system. With recovery processes there is relatively little waste but a large by-product processing cost, although the greater amount of by-product produced helps to offset these costs.

The amount of sulfite oxidized to sulfate in scrubber solutions is proportional to the relative amounts of oxygen and SO_2 absorbed. It also depends on the pH and temperature of the liquid as well as the composition of particulate emissions which may contain iron or copper that act as catalysts for the oxidation reaction. In general, however, as the gas SO_2 concentration becomes smaller, the fraction of sulfite oxidation tends to increase. For this reason, when lime or limestone scrubbing systems are used for low sulfur coal or for boilers operating on high excess air they may experience high sulfite oxidation and produce waste solids that are mainly gypsum. This can be a desirable feature since gypsum solids are more easily dewatered due to faster settling rates and higher final settled densities. Conversely the lower oxidation observed with high sulfur coals can lead to solid wastes high in sulfite and difficult to dewater.

Ash Content of Coal

Most coals fired in U.S. utility boilers contain 5 to 30 percent ash. After combustion, part of the ash falls to the bottom of the furnace and the remainder is carried upward with the flue gas. The fraction of the ash that is carried overhead is a function of the boiler design and combustion parameters. With pulverized coal firing, 85 percent or more of the ash appears as fly ash; in cyclone boilers about 20 to 30 percent of the ash goes overhead.

Fly ash can be removed upstream of the FGD system by a precipitator, fabric filter, or prescrubber, or integrally within the FGD system

itself. Not all FGD processes are suitable for combined removal. Even when fly ash is removed upstream, residual ash becomes entrained in the process liquor.

Fly ash is invariably abrasive; some is chemically inert, and some is highly acidic due to SO_3 adsorption. Fly ash can cause excessive erosion, scaling and plugging of equipment. It contributes to the waste volume of throwaway processes, the loss of absorbent for regenerative processes, and may contaminate the byproduct of recovery processes. Certain coals from Wyoming, Montana, and North Dakota produce alkaline fly ash with large amounts of reactive calcium, magnesium, sodium, and potassium oxides. With combined removal of alkaline fly ash and SO_2, major reduction in the alkali makeup requirement can be realized. The presence of calcium alkali in the ash can, however, aggravate wet-dry interface problems by producing hard insoluble deposits.

In general, only processes using nonregenerable absorbents (lime, limestone, soda) can be used for the combined removal of fly ash and SO_2. The fly ash is then disposed of together with the spent absorbent. Lime and limestone processes can better tolerate this fly ash and are sometimes used for combined removal. Venturi scrubbers are often used for this purpose at the expense of increased pressure drop over other absorption systems. However, the fly ash contributes to solids buildup at the wet-dry interface and causes erosion of pipes, pumps, spray nozzles, and scrubber internals.

Chlorine Content of Coal

The small amounts of chlorine in coal are converted to gaseous chloride in the boiler. The chloride is absorbed from the gas by wet scrubbing processes. Its presence provides the potential for chloride stress-corrosion, requiring in some places the use of high alloy equipment wherever rubber or other protective coatings are not applicable.

In wet scrubbing processes, dissolved chloride replaces active calcium, magnesium or sodium alkalis by their chloride salts, which are inactive in the absorption process. The alkali associated with the chloride is then lost as dissolved solids in the water portion of the waste sludge. From a cost standpoint this is particularly objectionable for magnesium and sodium based processes (or magnesium enhanced lime and limestone processes), because these alkalis are relatively expensive. For such processes, prescrubbing may be used to absorb chlorides from the flue gas upstream of the FGD system. This minimizes both alkali loss and chloride stress-corrosion problems. For lime and limestone processes, an equivalent amount of calcium is used up by the chloride (the amount is small relative to that used for SO_2 absorption), but the calcium is relatively inexpensive.

REHEAT OF SCRUBBED FLUE GASES

Purpose and Need for Reheat

Flue gases are normally discharged from the power plant air heater at 120 to 150°C (250 to 300°F). The temperature is selected to remain above the dew point of the traces of H_2SO_4 normally present in order to reduce corrosion and permit carbon steel to be used for fans, ducting, and stack lining.

When a wet scrubber is inserted between the air heater and stack for SO_2 removal, the flue gas exiting the scrubber is saturated with water and cooled to the saturation temperature of about 50°C (125°F). Discharge of the cool, wet gas to the stack can lead to:

- Condensation of water vapor and sulfur oxides, resulting in the acidic water corrosion of downstream ducts, fans, and stack lining
- Impaired plume rise and, hence, poorer dispersion of residual pollutants for a given stack height
- Deposition of scrubber residue on downstream fan blades, resulting in imbalance

- A visible plume as water vapor condenses
- Stack rain, or mist droplets, that can settle around the power station

To correct the above undesirable aspects of wet scrubbing, the treated gas may be reheated to a higher temperature before discharge.

Methods of Reheat

Flue gas can be reheated in many ways, and several approaches have been developed. The basic differences in reheat methods are the energy sources used and the methods of transferring that energy to the flue gas. Reheat methods currently in use include:

- Direct inline reheat — using steam or hot water heat exchangers
- Direct combustion reheat — using gas or oil in either inline burners or external combustion chambers
- Indirect hot air reheat — using steam to heat air which is then mixed with the scrubbed gas
- Bypass reheat — bypassing a portion of the untreated hot flue gas to mix with the scrubbed gas

In the U.S., the scrubbed gas is generally reheated by 15 to 40°C (30 to 100°F). Except for bypass, the energy penalty for reheat may range from 1 to 5 percent of the heat input to the boiler system.

Direct Inline Reheat. Inline steam reheat is the most prevalent method in the United States, although a few systems use hot water. An inline reheater consists of a heat exchanger installed in the flue gas duct, and is generally simple in design and installation. For a given degree of reheat, the energy consumption is lower than for other types of reheat, except bypass. The major problems encountered have been plugging, corrosion, and vibration of the heat exchanger tube bundles.

Plugging occurs from entrainment. Once the scrubber liquor deposits on the reheater, the dissolved and suspended solids bake onto it. This deposit continues to grow, blocking the gas flow, increasing the pressure drop, and helping to induce corrosion from the localized high temperature and concentrated salts. The effectiveness of the heat transfer surface is progressively reduced as the deposit builds up. To minimize problems, an efficient scrubber mist eliminator is essential. Most direct inline reheaters incorporate a steam or air soot blower for maintaining clean reheat surfaces. Corrosion and pitting have been attributed to periodic acid conditions and to chlorides. Effective design of the mist eliminator will minimize this. Operating experience suggests that certain materials should not be used, such as carbon steel, 304SS, 316SS, and Corten. Structural design against vibration is essential.

Direct Combustion Reheat. The major advantage of this type of reheat is operational reliability, especially if gas is used, because there is no heat transfer surface on which fouling can occur. The main drawback in the United States is the limited availability and cost of the oil or gas required. Where oil is used, problems have occurred in attempting to maintain the flame within the main flue gas stream. This saves space, but typically does not work well. An external combustion chamber of adequate size is essential. Refractory failures have occurred in the combustion chamber from flame impingement, attack from condensation during downtime, vibration, and too rapid heating. Careful specification of refractory and subcomponents is essential and provision must be made for the combustion chamber to be heated up slowly.

Indirect Hot Air Reheat. Indirect hot air reheaters have had fewer problems than inline types. One advantage of this type of reheat is that it provides desirable dilution for moisture content and residual pollutant concentrations in the stack gas. Disadvantages are higher capital investment, higher steam consumption for the same degree of reheat, and increased stack gas volume. The temperature of the hot air

before mixing is higher than 200°C (400°F) and can destroy the usual coatings used to protect ducts and scrubber walls. Hot air must be prevented from entering the system without cold gas flow during startup and shutdown. For the same degree of reheat, indirect hot air reheat has the highest energy requirement. However, for the same amount of energy consumption, it may have equal or better benefits than other types of reheat.

Bypass Reheat. Bypass reheat has the advantages of low capital investment, negligible operating cost, and simple, reliable operation. However, the maximum degree of reheat obtainable is limited by the overall SO_2 removal requirement versus the SO_2 removal capability of the FGD system. Separate fly ash removal is required to ensure that the bypassed flue gas is sufficiently low in dust content to meet particulate emission standards. Operating experience with bypass reheat in the United States is limited to only one installation, but additional FGD systems are under construction with provision for bypass reheat.

ALTERNATIVES TO REHEAT

A number of alternatives to reheating are available. Whether or not they are feasible must be considered on a case by case basis. To the extent that excessive ground concentration of residual pollutants is a problem due to reduced plume buoyancy, one alternative to reheating is to build a taller stack. Because there is no energy penalty, a taller stack could be more economical than reheating even though it involves a high capital cost.

To limit corrosion, one may either select materials that are inherently resistant to corrosion or use coatings to cover materials subject to corrosion. If the purpose of reheat is to protect a downstream fan, an alternative is to place the fan upstream of the scrubber, although this requires a precipitator to remove erosive particulate matter. Wet, or washed, fans have also been used.

Using reheat to overcome the effect of liquid entrainment from the scrubber is costly and not necessarily the best answer to such problems. The use of more efficient mist eliminators would be the preferred alternative. One form of liquid emission that would not be affected by better mist elimination results from liquid condensate forming inside the stack. Such an effect can be reduced or eliminated by the combination of insulation on the stack so as to reduce condensation likelihood, plus the use of a lower velocity stack.

There is very little, other than reheat, that is effective in eliminating a visible vapor plume. However, plume appearance and, in particular, the length of a visible plume are strong functions of atmospheric conditions. When the gas leaves the stack, water vapor condenses in the cooler atmosphere forming a visible plume. As the plume disperses, condensed vapor evaporates at a rate depending on the ambient humidity and temperature. With high external humidities early in the day, the visible plume may travel long distances before disappearing. In a desert environment at mid-day, on the other hand, the visible plume vanishes rapidly. If the purpose of reheat is a cosmetic one, one approach could be to use variable reheat. That is, reheat could be limited to those periods of atmospheric conditions during which a plume of objectionable length would otherwise occur.

Reheating should not be considered as a necessity, but as one of a number of approaches for consideration in optimizing sulfur dioxide absorption systems. Because of the high cost of reheat installation and operation, some FGD system operators have selected a "no reheat," or "wet-stack," design.